STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 99-03-36 DPUC DETERMINATION OF THE CONNECTICUT LIGHT AND POWER COMPANY'S STANDARD OFFER

December 15, 1999

By the following Commissioners:

Donald W. Downes
John W. Betkoski, III
Jack R. Goldberg

SUPPLEMENTAL DECISION

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SUPPLEMENTAL DECISION

I. INTRODUCTION

A. SUMMARY

In this Decision, the Department of Public Utility Control approves the final components of The Connecticut Light and Power Company's standard offer service. In particular, the Department herein establishes the two chief unbundled components of the standard offer service, the generation services charge and the competitive transition assessment. Standard offer service is available to all customers in CL&P's service territory beginning January 1, 2000, and is available to all customers who affirmatively choose to receive this full-service electricity offering, or who do not, or are unable to, arrange for or maintain electric generation services with a licensed electric supplier. Standard offer service extends through December 31, 2003, and is priced 10% below the fully bundled price for electricity at year-end 1996.

This Decision also approves NRG Power Marketing, Inc. and Duke Energy Trading and Marketing Northeast L.L.C. as the entities to supply one-half of electricity load to serve standard offer customers (with Select Energy, Inc. serving the other half). These suppliers were the winning bidders of the competitive solicitation conducted by the Department's consultant. Further, the Department sets the price CL&P will pay Select as equal to the weighted-average price resulting from the competitive solicitation. The Department also approves of CL&P's proposal to sell its entitlements in CL&P's nuclear units from January 1, 2000, through December 31, 2001.

B. BACKGROUND

On October 1, 1999, the Department of Public Utility Control (Department) issued a Decision in the instant docket (Original Decision) that required The Connecticut Light and Power Company (CL&P or Company) to make certain compliance filings. On October 22, 1999, in accordance with Order No. 1 in the Original Decision, the Company filed revisions to certain components of its standard offer rates (Order No. 1 Compliance). On November 5, 1999, pursuant to Order No. 2 in the Original Decision, CL&P filed certain revised exhibits to reflect the results of the bidding for the wholesale supply of standard offer generation service (Order No. 2 Compliance).

By letter dated November 3, 1999, the Company requested that the Department review and approve the sale of the energy and capacity from its nuclear units (Nuclear Output Sale). This request was made pursuant to the July 7, 1999 Interim Decision in the instant docket.

C. CONDUCT OF THE PROCEEDING

By Notice of Supplemental Hearing dated October 29, 1999, the Department held a public hearing on November 10, 1999, in its offices, Ten Franklin Square, New Britain, CT on the Order No. 1 Compliance. By Notice of Additional Supplemental

Hearing dated November 9, 1999, the Department scheduled a public hearing for November 19, 1999, on the Order No. 2 Compliance. By Amended Notice of Additional Supplemental Hearing, the Department included the Nuclear Output Sale in the public hearing to be held on November 19, 1999. That hearing was held in the Department's offices and continued to December 1, 1999, at which time it was closed.

The Department issued a draft Decision in this matter on December 9, 1999. All parties were provided an opportunity to file written exceptions to the draft Decision.

D. PARTIES AND INTERVENORS

Parties to the initial proceeding maintained their status in this supplemental proceeding. In addition, the Department granted intervenor status to Energy East Solutions, Inc.

II. DEPARTMENT ANALYSIS

A. STANDARD OFFER SERVICE GENERATION PROCUREMENT

By Interim Decision dated July 7, 1999, in Docket No. 99-03-36, DPUC Determination of The Connecticut Light and Power Company's Standard Offer (Interim Decision), the Department approved CL&P's proposal to procure Standard Offer Service (SOS) generation service 50% from competitive bidding and 50% from Select Energy, Inc. (Select Energy), a CL&P affiliate. Since competitive bidding was open to CL&P affiliates, fairness dictated strict adherence to the Code of Conduct contained in Section 16-244h-1 through 16-244h-7 of the Regulations of Connecticut State Agencies (Conn. Agencies Regs.). To assure that preferential treatment of CL&P affiliates did not occur during the bidding process, the Department: (1) mandated that CL&P develop distinct buy and sell teams during the bidding process; (2) authorized an independent, third-party to act as auction agent; and (3) exercised oversight of the competitive bidding process through its Utility Operations Management Audit Unit (UOMA).

The Department retained J.P. Morgan, a full service investment banking firm in New York City, to act as the Department's independent auction agent for the solicitation in accordance with the requirements of the Interim Decision and Public Act 98-28, An Act Concerning Electric Restructuring (Act). Tr. 11/19/99, p. 1971. The solicitation was conducted under UOMA supervision; according to J.P. Morgan, UOMA was apprised of all solicitation activity and worked together with J.P. Morgan throughout the entire auction process. Tr. 11/19/99, p. 1972.

The solicitation was conducted in one round. J.P. Morgan mailed approximately 500 copies of marketing materials to contacts, and telephoned a significant number of those contacts. J.P. Morgan, in conjunction with the Department, issued a press release on July 29, 1999 regarding the competitive solicitation process. J.P. Morgan also held a technical conference to provide additional information for bidders. Tr. 11/19/99, pp. 1972-1974. According to J.P. Morgan, the technical conference was scheduled so that J.P. Morgan, CL&P and UOMA could provide additional information to bidders so that they could formulate their bids. Id. Questions associated with the

Request for Proposals (RFP) and bids submitted under the RFP, including those from Select Energy, were all directed to J.P. Morgan. With the exception of the technical conference, J.P. Morgan was the single point of interface between potential bidders and the solicitation. Corey PFT, p. 1.

On September 20, 1999, J.P. Morgan received eight final bids to provide portions of the approximately 2,000 MW in SOS generation put out to competitive bid. Subsequently, J.P. Morgan prepared an in-depth analysis of the key terms of each of the bids. J.P. Morgan's primary selection criterion was least cost standard offer service. Tr. 11/19/99, pp. 1975, 1989. According to J.P. Morgan, the winning bidders not only provided least cost service, they own approximately 4,200 MW of generation in New England, and are leading global providers of generation and power services. Consequently, J.P. Morgan believes that the winning bidders have the financial wherewithal to stand by their contracts. Tr. 11/19/99, pp. 1976-1978, 2001-2002.

J.P. Morgan, its outside counsel, and CL&P's sell team met with the winning bidders, NRG Power Marketing Inc. (NRG) and Duke Energy Trading and Marketing Northeast L.L.C. (Duke), to negotiate the final terms of the contracts. Tr. 11/19/99, pp. 1976-1977. In accordance with the Interim Decision, the price CL&P will pay Select is derived from, and equal to the weighted-average price resulting from the competitive solicitation. Dabbar PFT, p. 6.

Standard Offer Service Generation Supply

	2000	**2001**	**2002**	**2003**
Percent of Total				
NRG	35%	40%	40%	45%
Duke	15%	10%	10%	5%
Select	50%	50%	50%	50%
	100%	100%	100%	100%

The Department approves the results of the solicitation for competitive bidding. The competitive solicitation process was conducted in a manner that did not afford CL&P's affiliates preferential treatment. The competitive solicitation was marketed aggressively to engender sufficient interest. Moreover, the competitive solicitation elicited a least cost solution to the procurement of SOS generation service.

B. Retail GSC Rates and CTA Recovery

The Department must establish unbundled SOS rates while maintaining the 10% rate reduction mandated by the Act. This requirement, combined with other provisions of the Act, places certain rate design limitations on the Department. The Act fixes certain charges, such as the Conservation and Renewables charges, leaving the Department no discretion in setting those rates. The Systems Benefits Charge (SBC), Distribution and Transmission rates are cost-based and are designed to recover CL&P's annual costs for these services to avoid creating deferrals. Therefore, the Department has little discretion in setting these rates. However, the Act does provide the Department flexibility in setting the Competitive Transition Assessment (CTA) and Generation Services Charge (GSC) during the SOS period. Flexibility in designing these rates is necessary to recover stranded costs over a reasonable period, set GSC rates that will stimulate competition, and maintain the Act's mandatory 10% rate reduction. The Department has balanced the CTA and GSC rates to accomplish these goals.

Generation Service Allocation by Rate

	Retail GSC Rates	
	Proposed (1)	Approved
Residential		
1 Res. Electric Service (Non-Heating)	4.7	5.5
5 Res. Electric Heating Service	4.7	4.9
7 Res. Time of Day	4.7	4.9
Small C&I		
18 Controlled Water Heater	4.6	4.6
27 Small Time-Of-Day General Service	4.6	4.6
30 Small General Electric Service	4.6	4.6
40 Small Church & School Electric Service	4.6	4.6
115 Unmetered Electric Service	4.6	4.6
Large C&I		
35 Intermediate General Electric Service	4.5	4.5
41 Large Church & School Electric Service	4.5	4.5
55 Intermediate Time of Day Electric Service Manufacturers	4.5	4.4
56 Intermediate Time of Day Electric Service Non-Manufacturers	4.5	4.4
57 Large Time of Day Electric Service	4.5	4.4
58 Large Time of Day Electric Service Non-Manufacturers	4.5	4.4
21 Intermediate Interruptible Service	4.5	4.4
39 Large Interruptible Service	4.5	4.4
Flex Contracts	4.5	4.4
984 Supplemental Power Service	4.5	4.4
985 Back-up and Maintenance Power Service	4.5	4.4
119 Standby & Auxiliary Power	4.5	4.4
Street & Outdoor Lighting		
29 Outdoor Recreational Lighting	4.2	4.0
116 Street & Security Lighting	4.2	4.0
117 Partial Street Lighting Service	4.2	4.0

(1) November 5, 1999, Compliance Filing: Exhibit 17

The Department has increased the proposed GSC rates, establishing rates that will recover CL&P's cost for standard offer supply plus the cost of all appropriate adders to provide retail service. However, CL&P does not incur retail adder costs; therefore, CL&P will recover revenues in excess of its actual cost to supply SOS from customers that remain on that service. Given that a 10% reduction must be maintained and that the CTA and GSC are the only unbundled rates that can be adjusted, an increase to the GSC necessitates a decrease to the CTA. The result is a GSC that is designed to recover a portion of CTA costs. Moreover, the approved GSC rates fall within the range of retail adders specified in the wholesale supply contract for SOS generation with NRG Power Marketing Inc. (NRG). As a consequence, there will be no additional cost at the wholesale level to provide GSC rates at the approved retail levels.

GSC rates that were adjusted by the Department include recovery of CTA revenues. Therefore, customers who switch to a competitive supplier will no longer provide that portion of CTA revenue embedded in their GSC rate. The Department understands CL&P's concern regarding the CTA recovery period and fairness of the proposed rate design. This issue was considered when designing the GSC rates.

The Department examined the effect on CTA recoveries based on varying percentages of customer switching throughout the standard offer period. The Department believes that customer switching among the residential and small commercial classes will be somewhat limited initially due to the phase-in for choice in 2000 and because many of these customers likely will not change electric suppliers until others have done so, essentially taking a wait-and-see approach. Therefore, the Department believes that switching will not bear significantly on CTA recovery through 2002.

The Department notes that CL&P calculated all unbundled rates based on a forecasted level of sales through 2003. However, sales may increase beyond those projected due to reduced rates or other factors. Increased sales will provide CTA revenues that have not been considered in this case. In addition, as discussed above, the Department has carefully considered recovery of the CTA and the goal of stimulating retail choice in setting GSC rates. This Decision provides for reasonable recovery of stranded costs; however, the Department will monitor actual recovery in the future and make adjustments as necessary.

C. Energy Adjustment Clause

The Department approved an Energy Adjustment Clause (EAC) for the limited purpose of changes to the cost of wholesale SOS generation. Original Decision, pp. 11-12. The Company's EAC proposal in its compliance filing would automatically pass costs to customers that the Department does not intend to be recovered from them. See Late Filed Exhibit No. 38.

The Company claims that it is necessary to continue the EAC because of: (a) mismatches in billing cycle versus supply charge periods might occur (the billing problem); and (b) the variance in rate design between the generation service supply and retail pricing (the equalization problem). Response to Interrogatory EL-91. The recovery of these costs was rejected. Original Decision, p. 12.

Section 20(a)(3)(e) of the Act states that electric distribution companies shall be entitled to recover reasonable costs incurred as a result of providing SOS generation, default service or back-up service. Each of these stated services is provided at the wholesale level. In contrast, the billing problem is at the retail level. See Tr. 11/19/99, p. 2069. The protection provided by Section 20(a)(3)(e) does not extend to the billing problem. In addition, the magnitude of the billing problem is speculative at this time. Tr. 11/19/99, p. 2068.

The Company admits that it is feasible to solve the equalization problem internally. Tr. 11/10/99, p. 1835. Continuance of the EAC would therefore act as a disincentive for the Company to solve this problem of its own accord.

The winning bids to provide SOS generation are fixed. There will be no variance in the cost to procure wholesale energy and capacity; therefore, there are no costs to pass through the EAC. Response to Interrogatory EL-91. The only situations in which the SOS cost of power to CL&P could change is if the Department changes the GSC outside the range agreed to by some SOS suppliers. If this occurs, the Department could either (1) pass the additional SOS cost through the EAC, or (2) adjust collection of the CTA through the GSC.

For the foregoing reasons, CL&P's proposed EAC tariff is rejected and the following language is approved in its place:

> The Company shall reconcile the revenues billed to customers taking Standard Offer Generation Service against DPUC-approved costs of acquiring such service and recover or refund, with interest calculated at the Company's cost of capital used for its distribution rate, any under or over-collection in accordance with an annual reconciliation. When the EAC rate is zero it will not be shown on customer bills.

The Department will consider modifications to the CTA collection through the GSC or allow changes to the SOS supply cost to be passed through the EAC if the need arrives. The EAC will only be instituted in special circumstances approved by the DPUC. Regardless of the option chosen, CL&P will be made whole for any changes to the cost to supply SOS resulting from a change to the GSC.

D. Rate 980

The Company proposes to modify Rate 980 by substituting NEPOOL market clearing prices for the marginal energy cost to provide electricity. Late Filed Exhibit No. 38. The new pricing would be based on either (a) the hourly NEPOOL market clearing price (if a time differentiated meter is installed), or (b) the average NEPOOL market clearing price over the billing period (if no time differentiated meter is installed). Id. Since CL&P no longer owns generation, there is no cost to develop Rate 980 under the existing method. The NEPOOL market price of energy is the price generators can receive by selling non-firm power into the New England market. The ISO market price is the avoided cost to displace one kwh and therefore CL&P's proposal is appropriate and is approved.

E. Interim Nuclear Capital Recovery Mechanism

The Original Decision ordered the Company to calculate a revised interim nuclear capital recovery mechanism (INCRM) subject to several revisions. The revisions required by the Decision included: 1) removal of treatment as "costs of mitigation" of those costs classified by the Company as "unavoidable O&M"; 2) return of and on post-June 30, 1997, capital additions; 3) use of nuclear operating expenses approved in the last rate case; and 4) incorporation of market values for energy and capacity, including actual data from the nuclear entitlement sale. Decision, p. 98.

The Company's October 22, 1999, compliance filing included a revised INCRM, reflecting the Company's interpretation of the Original Decision. Compliance Filing dated October 22, 1999, Exhibit 5, Schedule F. The Company properly reclassified expenses previously described as "unavoidable O&M," removing them from qualification for special consideration as costs of mitigation.

The Company included post-June 30, 1997 capital additions in two categories. For those capital additions incurred from July 1, 1997, to December 31, 1999, the Company included a line item in the INCRM that recovers these expenditures in year 2000. For those capital additions incurred after December 31, 1999, the expenditures are recovered in their entirety in the year they are incurred. The Company states that capital additions were afforded this treatment by the Decision, since it allowed a recovery of additions but did not allow recovery of the balance from sales proceeds at the time of the sale of the nuclear units. Response to Interrogatory EL-88. This treatment does not comport with the Decision, in which the Department stated the following:

> The Department believes that, as a necessary cost of nuclear unit operation, return of and on capital additions should be allowed. Simply including capital expenditures in the [discounted cash flow] analysis does not lead to their recovery; rather, it simply recognizes them as an ordinary cost of unit operation for the purpose of calculating the interim market value of the unit. Therefore, the inclusion of capital expenditures in the analysis is a necessary input in determining the income capitalization value and applies to all capital additions past June 30, 1997. Since the

> Stranded Costs Decision capitalized these expenditures, the Department believes this is a reasonable method to incorporate them in the income capitalization value calculation also. However, these costs will not be allowed as an offset to the purchase price at time of sale.

Decision, p. 70.

The Department went on to state that it will allow the Company "a return of and on its nuclear capital additions." Id., p. 72. The intent of the Decision was to allow the Company to recover a return on its investment using previously approved amortization rates over the life of the units, consistent with standard accounting practice. However, the remaining investment is not to be added to plant balances, and therefore is not subject to stranded cost recovery. This is also consistent with the Department's October 1, 1999, Decision in Docket No. 99-03-35, DPUC Determination of The United Illuminating Company's Standard Offer, in which the Department stated:

> The Department allows the return of and on capital additions in the IOCRM [INCRM] as proposed by UI for each year of the interim period. However, Section 8(a)(7) of the Act does not allow recovery of capital additions after 1997 that were not previously approved. Capital additions were approved for 1997-2001 as part of the Rate Plan and, therefore, 2000 and 2001 capital additions that are prudently incurred and reviewed by the Department are appropriately added to rate base at the time of the nuclear asset sale. Capital additions after 2001 have not been previously approved and therefore will not be added to stranded plant balances when the nuclear facilities are sold.

Decision, p. 62.

Therefore, the Department allowed full recovery of capital additions that were approved in rates for UI, but allowed only a return of and on capital additions (using standard amortization rates) for the capital additions incurred subsequent to that period. The treatment of capital additions that the Department intends for CL&P is entirely consistent with the treatment for UI, with the exception of the time period required for qualification for full recovery (pre-July 1, 1997 for CL&P vs. pre-2002 for UI). Capital additions for UI were approved for recovery through 2001 because the five-year rate plan was approved before the June 30, 1997 date in Section 8(a)(7) of the Act. At the time the act was passed, CL&P had not had a rate case since 1992 and therefore had no post-June 30, 1997 capital additions approved for inclusion in rates. This time period is set strictly by Section 8(a)(7) of the Act. The Department will therefore reset the amortization of capital additions to the life of the nuclear units, consistent with standard accounting practice. However, as previously stated, the unrecovered balance of post-June 30, 1997 capital additions is not subject to further recovery.

Consistent with the Original Decision, the Company revised the INCRM to incorporate revenue data derived from the sale of the unit entitlements. Compliance Filing dated October 22, 1999, Exhibit 5, Schedule F. The revenue data are based on the competitive sale of the output from the units. The Company later amended the filing to correct an error regarding the sale price of Seabrook entitlements. This correction increases revenue from the nuclear units by $1.3 million over two years. Response to Interrogatory EL-84; Tr. 11/10/99, p. 1191. The data are consistent with the Original Decision; therefore, the Department will accept them as filed, including the above correction.

The Company revised the INCRM to incorporate nuclear operations and maintenance (O&M) data reflective of costs approved in the last rate case. The total nuclear O&M cost is $213 million. Compliance Filing dated October 22, 1999, Exhibit 5, Schedule F. The Company represented approved nuclear O&M costs as $203 million in its written exceptions to the draft of the Original Decision. Response to Interrogatory EL-85. The Company states that the discrepancy is due to two factors: 1) the $203 million amount inadvertently included a $5.7 million adjustment related to Millstone Unit 1, which should not have been included in the calculation since it is only relevant to the operating nuclear units; and 2) the use of cost of service factors for the allowed cost of service study that are different from the allocation methodologies used in the budget/forecasting process and the Management Information Budgeting System. Id.

The $5.7 million adjustment for Millstone Unit 1 is clearly an error, and this amount should be added to the $203 million amount, arriving at approximately $208.7 million. The remaining $4.3 million is more difficult to identify, since it originates from the net result of two different methods of identifying and allocating costs. The $213 million is the nuclear operating cost identified by the cost of service study approved in the Decision dated February 5, 1999, in Docket No. 98-01-02, DPUC Review of The Connecticut Light and Power Company's Rates and Charges – Phase II, and does not include any other costs recovered by the Company in other charges, such as the distribution rate. Tr. 11/10/99, p. 1810. Previously in this proceeding, the Company had proposed to assign administrative and general (A&G) costs to distribution that had been allocated to nuclear, fossil, and hydroelectric generation. In the Original Decision, this request was denied and the Department allowed these costs to be collected in the appropriate functional areas. Decision, p. 20. The return of these costs to the nuclear function is appropriate. Therefore, the $213 million is the proper amount of nuclear O&M to be used in the INCRM.

Consistent with the Department-adjusted INCRM below, the Company will be allowed to add $1.977 million to stranded costs for 2000 and $4.731 million for 2001. When the true-up for the sales value for nuclear is calculated, the total potential sales value of CL&P's nuclear assets of $139.2 million will be adjusted downward to reflect the appropiate depreciation amounts. The Department will calculate the interim nuclear recovery for 2002 and 2003 in the future if the units are not sold using the costs from the Rate Case Decision and the most recent forecast of sales and revenues.

The proposed and Department-approved INCRMs are as follows.

Connecticut Light and Power Company
Interim Nuclear Capitalization Value Calculation
(Thousands of Dollars)

	Compliance Filing			Department Adjusted	
	2000	2001		2000	2001
Energy and capacity revenues	$ 314,597	$ 316,308		$ 315,247	$ 316,958
Less operating costs:					
- O&M	213,078	213,078	(1)	213,078	213,078
- Fuel	47,698	47,698		47,698	47,698
- Property Taxes	19,122	19,122		19,122	19,122
- Unemployment Taxes	7,769	7,769		7,769	7,769
- Return of and on post 7/1/97 capital additions	17,684	0	(2)	2,530	2,449
- Return of and on new capital value	33,672	34,959	(3)	2,641	7,814
- Return on other rate base	3,822	3,822		3,822	3,822
- Return of and on market value	20,564	19,937		20,564	19,937
Subtotal - net revenue/(expense)	(48,813)	(30,078)		(1,977)	(4,731)
Unrecovered Capital Additions (4)	28,249	10,140		0	0
Deferral of market value return of and on	20,564	19,937		0	0
Total - net revenue/(expense)	$ -	$ -		$ (1,977)	$ (4,731)

Notes:
(1) Reflects the sale of the nuclear units
(2) Reflects the recovery of the post 6/30/97 cap. additions over the life of the units versus in a one year period.
(3) Reflects the recovery of the new cap. additions over the life of the units versus in a one year period.
(4) Unrecovered capital additions represent the portion of total capital additions made after June 30, 1997 which the Company will be responsible to collect even though it may not be recovered based on the revenue and expense assumptions used in this calculation.

F. NUCLEAR ENTITLEMENTS AUCTION

By Interim Decision dated July 7, 1999, the Department approved CL&P's proposal to sell or reassign its retained generation assets instead of using these assets to serve Standard Offer Service (SOS). The Department stated that it would monitor the sale or reassignment of these assets. Decision, p. 6. Pursuant to Section 8(c)(1) of the Act, the Company is obligated to maximize the benefits obtained from its entitlements to nuclear output. To grant approval, the Department must determine the auction results provide the most beneficial alternative for ratepayers.

On July 12, 1999, CL&P issued an initial RFP to 240 energy-related entities throughout the Northeast. The initial RFP was for output from the Company's nuclear entitlements for the entire four-year standard offer period. Upon further review of its divestiture plan, CL&P shortened the period of time to a maximum of two years, January 1, 2000 through December 31, 2001. The Company received 12 bids and selected those that would provide the greatest revenues. Tr. 11/10/99, pp. 1865-1866. The Northeast Utilities Service Company conducted the auction on behalf of CL&P and WMECO, without oversight by UOMA. Tr. 11/10/99, pp. 1869-1870.

In response to the Interim Decision, CL&P, together with its affiliate, the Western Massachusetts Electric Company (WMECO), agreed to sell entitlements to its share of the output of Millstone Units 2 and 3 and Seabrook Station to Select Energy, Inc. (Select); Consolidated Edison Energy, Inc. (ConEd); Constellation Power Source, Inc. (CPS); PECO Energy Company (PECO); Duke Energy Trading and Marketing, L.L.C. (Duke); and PP&L Energy Plus, Co. L.L.C. (PP&L). Select, ConED, CPS, PECO, Duke and PP&L were winning bidders in a Request for Proposals (RFP) to purchase contract entitlements in CL&P's nuclear units that was issued earlier this year. Together, CL&P and WMECO's entitlements total approximately 1,670 Megawatts. Bids were solicited for a minimum term of one year and a maximum term of two years, ending December 31, 2001. See the Letter from the Company to the Department, dated November 3, 1999.

According to CL&P, each of the six contracts with the winning bidders contains a provision entitled "DPUC Consent," which recognizes the need for the Department to authorize the sale before each agreement would be considered to be final. Tr. 11/10/99, p. 1841. The contracts are set to begin January 1, 2000. According to the Company, two purchasers of nuclear output are "heavily involved" in serving CL&P standard offer service. Tr. 11/10/99, pp. 1841-1843.

The Company states that it would be inappropriate to serve standard offer using nuclear output as the primary resource. According to CL&P, it would be uneconomical to provide the firm requirements service for standard offer with base load generation from nuclear units. Tr. 11/10/99, pp. 1920-1922. The risk of a forced outage during peak demand is too great: if such an outage were to occur, it might result in "astronomical" financial losses in a short period of time. Id. To mitigate this risk, a diverse generation portfolio is necessary.

According to the Company, it would be less beneficial to retain nuclear entitlements and sell the output to the wholesale spot market. The Company's revenue stream would be impossible to predict, which would be an untenable position for a facility with such a high level of fixed costs. CL&P asserts that since the spot market for capacity is so thin, it is possible the Company would be forced to settle for a price of zero. Tr. 11/10/99, pp. 1906-1908.

The Department believes that it would be inefficient to use base load generation resources alone to either serve firm requirements or to float on the spot market. To do either, CL&P would need to diversify its generation portfolio, which is not the intent of the Act. Finally, the per Megawatthour price to obtain nuclear entitlements is reasonable in comparison to the Department's base load resource market price forecast developed in the Stranded Cost Decision.[1] See the Proprietary Response to

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[1] The Decision dated July 7, 1999, in Docket No. 99-02-05, Application of The Connecticut Light and Power Company for Calculation of Stranded Costs.

Interrogatory OCC-259. The competitive bidding has produced reasonable prices for entitlements to nuclear output. In addition, CL&P has chosen the most beneficial means by which to treat its nuclear entitlements during the Interim Nuclear Recovery period. The Department approves the sale of CL&P's nuclear entitlements.

G. ASSIGNMENT OF MARKET-BASED CONTRACTS

Order No. 1 in the Original Decision requires the Company to submit a net present value calculation for the 30 Market-Based Contracts (MBCs) it intends to assign to its unregulated affiliate, Select Energy, Inc. (Select). The Decision required the net present valuation to be based on the Market Price Forecast (MPF) approved in the Decision dated July 7, 1999, in Docket No. 99-02-05, Application of The Connecticut Light and Power Company for Calculation of Stranded Costs (Stranded Cost Decision), and to reflect firm, non-firm or interruptible requirement service as contractually appropriate. In addition, the authorized calculation would include costs for ancillary services, distribution losses and Independent System Operator – New England (ISO-NE) O&M. Standard Offer Decision, p. 81.

In accordance with the Decision dated February 5, 1999, in Docket No. 98-01-02, DPUC Review of The Connecticut Light and Power Company's Rates and Charges – Phase II (Rate Case Decision), the total, net present value of the MBCs for the remainder of their respective contract terms will be used to offset stranded costs. To determine the value for the MBCs, contract prices for capacity and energy must be netted against comparable market prices. The 30 MBCs will provide a net benefit to the seller of capacity and energy, because contract prices will be higher than comparable market prices. The total value of that benefit, however, is subject to contention.

Pursuant to the Rate Case Decision, the Company estimated the net present value for 24 MBCs to be $54 million. June 9 Revision, p. 34. The Department recognized that it would need to revisit this issue as divestiture approached. Further, the approved inclusion of six additional MBCs to be assigned necessitates an updated valuation of the total, net present value for the MBCs.

The Company submitted two separate valuations for the 30 MBCs. The two valuations are distinguishable by their underlying market prices for capacity and energy. One valuation used the MPF price path (MPF Valuation) to calculate a net present value of approximately $75 million. The other valuation used the winning bids for CL&P's Standard Offer Auction and Nuclear Entitlement Auction Results Valuation (ARV) to determine a market price path: this yielded a net present value of approximately $15 million. In contrast to purchase power agreements, the MBCs are not subject to true-up, since they will be transferred to an unregulated affiliate. As a consequence, there is risk to ratepayers and to the Company that actual market prices will vary from projections.

According to CL&P, the MPF Valuation is inappropriate because it relies on a projected price path for output from base load generation facilities. It understates the value of firm service requirement contracts providing resources to serve variable load. Tr. 11/19/99, pp. 2156-2157. Alternatively, CL&P calculated the value for the 30 MBCs using a hybrid of the results from the winning bids in the Company's Standard Offer

Auction and Nuclear Entitlement Auction. The Company estimated the market price for firm services energy requirements based on the winning bids to provide SOS generation; it used the winning bids for its nuclear entitlements to derive the market price for capacity. Tr. 11/19/99, pp. 2150-2155. According to CL&P, the ARV is superior because: (a) it better reflects the value of the MBCs; and (b) it is based on actual bidding. Id.

The auctions yield actual market prices to serve firm requirements contracts. These prices are higher than the MPF from 2000-2003. Beyond 2003 actual prices are escalated. The resulting market prices are lower than the MPF after 2003. The Department believes that the ARV prices better reflect the costs to serve load that requires base, intermediate and peaking generation. The Department approves the methodology used to derive the ARV pricing.

It is inappropriate, however, to use a 14% rate of return as the discount rate as proposed by CL&P. The Company generally uses its weighted cost of capital in economic analysis. There is no justification for a change in this case. The Department approves a discount rate of 8.13%. This increases the value to $24.3, as indicated in Late Filed Exhibit No. 45.

Some of the values in Late Filed Exhibit No. 45 appear to be incorrect. In particular, the value of the contracts should be higher in the ARV than the MPF analysis after 2003, since the ARV market prices are lower during that period. For several contracts, however, the values are lower. The Department will add $6 million to account for this error. The resulting offset to stranded costs is $30.3 million.

III. FINDINGS OF FACT

1. The Department exercised oversight of the competitive bidding process for SOS generation through its Utility Operations Management Audit Unit.

2. J.P. Morgan acted as the auction agent for the SOS generation auction.

3. The solicitation to supply SOS generation was conducted in one round.

4. J.P. Morgan received eight final bids to provide portions of the approximately 2,000 MW in SOS generation put out to competitive bid.

5. J.P. Morgan's primary selection criterion for winning bids was least cost standard offer service.

6. The price CL&P will pay Select for SOS generation service is derived from, and equal to the weighted-average price resulting from the competitive solicitation.

7. The Department must establish unbundled SOS rates while maintaining the 10% rate reduction mandated by the Act.

8. The approved GSC rates fall within the range of retail adders specified in the wholesale supply contract for SOS generation with NRG Power Marketing Inc.

9. The wholesale cost to supply SOS generation is fixed.

10. The Company's compliance filing reflects full recovery in 2000 of capital additions incurred from July 1, 1997, to December 31, 1999.

11. The Company's compliance filing reflects full recovery of capital additions after 1999 in the year they are incurred.

12. The Company revised the INCRM to incorporate revenue data derived from the sale of the nuclear unit entitlements.

13. The Company revised the INCRM to incorporate nuclear O&M data reflective of costs approved in the last rate case.

14. By Interim Decision dated July 7, 1999, the Department approved CL&P's proposal to sell or reassign its retained generation assets instead of using these assets to serve Standard Offer Service.

15. On July 12, 1999, CL&P issued an RFP regarding output from its nuclear entitlements to 240 energy-related entities throughout the Northeast.

16. The Company received 12 bids and selected those that would provide the greatest revenues.

17. The Northeast Utilities Service Company conducted the auction on behalf of CL&P and WMECO.

18. CL&P and WMECO agreed to sell entitlements to its share of the output of Millstone Units 2 and 3 and Seabrook Station to Select Energy, Inc.

19. Together, CL&P and WMECO's entitlements total approximately 1,670 Megawatts.

20. The Company's 30 Market Based Contracts will provide a net benefit to the seller of capacity and energy, because contract prices will be higher than comparable market prices.

21. Pursuant to the Rate Case Decision, the Company estimated the net present value for 24 MBCs to be $54 million.

22. The MBCs are not subject to true up, since they will be transferred to an unregulated affiliate.

23. ARV prices are higher than MPF prices during the SOS period, and lower afterwards.

IV. CONCLUSION AND ORDER

A. CONCLUSION

Based on the evidence presented, the Department concludes that the solicitation for competitive bidding for standard offer service generation elicited least cost energy and approves the results. The Department also concludes that the Generation Services Charges approved herein should stimulate competition and provide for recovery of stranded costs over a reasonable period of time, while maintaining the 10% rate reduction mandated by the Act. Further, the Department finds that the competitive bidding of the output of CL&P's nuclear entitlements has produced reasonable and approves the sales. Finally, the Department finds that the Standard Offer Auction and Nuclear Entitlement Auction Results Valuation is appropriate for valuing the Company's Market Based Contracts

B. ORDER

For the following Order, please submit an original and 15 copies of any requested material to the Executive Secretary, identified by Docket Number, Title and Order Number.

1. No later than December 22, 1999, the Company shall revise its compliance filing as discussed in Section II, above.

DOCKET NO. 99-03-36 DPUC DETERMINATION OF THE CONNECTICUT LIGHT AND POWER COMPANY'S STANDARD OFFER

This Decision is adopted by the following Commissioners:

Donald W. Downes

John W. Betkoski, III

Jack R. Goldberg

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Department of Public Utility Control, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

	December 16, 1999
Louise E. Rickard Acting Executive Secretary Department of Public Utility Control	Date

CL&P LIST AND APPLICABILITY OF RATES AND RIDERS

Rate 1 — **Residential Electric Service (Non-Heating)** Single family homes, apartments, and farms where residential uses are more than 50% of energy use. Includes Controlled Water Heating Block Pricing (No New Installations)
- Other Available Rates/Riders: Rate 7 and Rider N
- Effective 1/1/00

Rate 5 — **Residential Electric Heating Service** Single family homes, apartments, and farms where residential uses are more than 50% of energy use. Includes Controlled Water Heating Block Pricing (No New Installations)
- Other Available Rates/Riders: Rate 7, Rider N and CSR (Construction Standard Rider)
- Effective 1/1/00

Rate 7 — **Residential Time-Of-Day Service** Optional Rate for Residential
- Other Available Rates/Riders: Rider N, Rates 1 or 5 as applicable
- Effective 1/1/00

Rate 18 — **Controlled Water Heating Electric Service** Optional Rate used for water heating only, no space or C&I process heating. - Small General Service Rates with restricted applicability for Residential.
- Other Available Rates: Rates 27, 30 and 35
- Effective 1/1/00

Rate 21 (closed) — **Intermediate Interruptible Service** Optional Rate for Customers with at least 300 kW of interruptible load. Energy charges are based on weekly forecast of Marginal Energy Cost. Interruptibles are based on both price and reliability.
- Closed to new applicants effective 2/5/99.
- Other Available Rates/Riders: Rider LTED
- Effective 1/1/00

Rate 27 — **Small Time-Of-Day General Electric Service** Optional Rate for Small General Service Customers
- Other Available Rates/Riders: Rates 30 and 35, Riders N, 5 Yr. ED and TDR
- Effective 1/1/00

Rate 29 — **Outdoor Recreational Lighting Service** Optional for Lighting Only between 7 PM and 7 AM.
- Other Available Rates: Rates 27, 30 and 35
- Effective 1/1/00

Rate 30 — **Small General Electric Service** General Service for Customers with Annual Maximum Demands less than 350 kW.
- Other Available Rates/Riders: Rates 18, 27 and 35, and Riders N, 5 Yr. ED and TDR
- Effective 1/1/00

CL&P LIST AND APPLICABILITY OF RATES AND RIDERS

Rate 35 **Intermediate General Electric Service** General Service for Customers with Annual Maximum Demands less than 350 kW.
- Other Available Rates/Riders: Rates 18, 27 and 30 and Riders A, N, 5 Yr. ED, TDR, CPR, BR, and, in rare cases, VCR
- Effective 1/1/00

Rate 39 (closed) **Large Interruptible Service** Customers with at least 2000 kW interruptible load. Interruptions are based on reliability.
- Closed to new applicants effective 2/5/99.
- Available Riders: LTED and TDR
- Effective 1/1/00

Rate 40 (closed) **Small Church and School Electric Service** open only to existing customers on Rates 40 and 41 with Annual Maximum Demands less than 350 kW, Non-Profit Schools only.
- Other Available Rates/Riders: Rates 18, 27, 30 and 35 and Riders N, TDR and CPR.
- Effective 1/1/00

Rate 41 (closed) **Large Church and School Electric Service** Mandatory Time-Of-Day for Customers with Annual Maximum Demands greater than or equal to 350 kW, Non-Profit Schools only, open only to existing customers on Rates 40 and 41.
- Other Available Rates/Riders: Rates 21 and 56 and Riders TDR, DRR, VCR and CPR.
- Effective 1/1/00

Rate 55 **Intermediate Time-Of-Day Electric Service Manufacturers** Mandatory for Customers with Annual Maximum Demands greater than or equal to 350 kW but less than 1000 kW. Sales Tax Exempt Industrial Customers only.
- Other Available Rates/Riders: Rates 21, and Riders 5 Yr. ED, BR, CPR, TDR, DRR, VCR, and LTED.
- Effective 1/1/00

Rate 56 **Intermediate Time-Of-Day Electric Service Non-Manufacturers** Mandatory for Customers with Annual Maximum Demands greater than or equal to 350 kW but less than 1000 kW. Non-Sales Tax Exempt C&I Customers and large governmental, educational, and religious institutions.
- Other Available Rates/Riders: Rates 21 and Riders 5 Yr., ED, BR, CPR, TDR, DRR, VCR, and LTED.
- Effective 1/1/00

Rate 57 **Large Time-Of-Day Electric Service Manufacturers** Mandatory for Customers with Annual Maximum Demands greater than or equal to 1000 kW. Sales Tax Exempt Industrial Customers only.
- Other Available Rates/Riders: Rates 21 and 39, and Riders 5 Yr. ED, BR, CPR, TDR, DRR, VCR, and LTED.
- Effective 1/1/00

CL&P LIST AND APPLICABILITY OF RATES AND RIDERS

Rate 58 — **Large Time-Of-Day Electric Service Non-Manufacturers** Mandatory for Customers with Annual Maximum Demands greater than or equal to 1000 kW. Non-Sales Tax Exempt C&I Customers and large governmental, educational, and religious institutions.
- Other Available Rates/Riders: Rates 21 and 39, and Riders 5 Yr. ED, BR, CPR, TDR, DRR, VCR, and LTED.
- Effective 1/1/00

Rate 115 — **Unmetered Electric Service** Special Purpose and Lighting Applications with Fixed Schedule of Constant Usage, Customer Owned Equipment.
- Effective 1/1/00

Rate 116 — **Street and Security Lighting** Road and Parking Lighting using Company Owned Equipment and Poles, Unmetered.
- Effective 1/1/00

Rate 117 — **Partial Street Lighting Service** Road and Parking Lighting using Customer Owned Poles and/or Equipment, Unmetered.
- Effective 1/1/00

Attachment 3 — **Monthly Street Lighting Rates for Partial Service** Closed Rate, A Mix of Company and Customer Ownership of Equipment and Energy.
- Effective 1/1/00

Rate 980 — **Non-firm Power Purchase** Customers that are Qualifying Facilities with excess energy to sell to the Company, in conjunction with, or without, Firm Power Purchase Contract .
- Effective 1/1/00

Rate 984 — **Supplemental Power Service** Customers that self-generate but need additional energy regularly to operate.
- Other Available Rates/Riders: General Service Rates are available for this service.
- Effective 1/1/00

Rate 985 — **Back-Up and Maintenance Power Service** Customers that self-generate with a need for service during periods when the Customer's generation is unavailable.
- General Service Rates are available for this service.
- Effective 1/1/00

Rate TR — **Temporary Interruptible Rider** Available to customers, when deemed necessary by CL&P or CONVEX during capacity deficiency periods, when reliability may be threatened.
- Customer must be available to generate or interruptible at least 200 kW of load normally supplied by CL&P within one hour after notification by CL&P.

CL&P LIST AND APPLICABILITY OF RATES AND RIDERS

- Subscription and payment information for Rate TR is available by contacting CL&P.
- Effective 11/6/96

Rider A **Optional Off-Peak Service** Limits the measurement of Production and Transmission Demand and the determinant of the energy first block to maximum monthly on-peak demand.
- Other Available Rates/Riders: Rate 35
- Effective 1/1/00

Rider N **Self-Generator Net Energy Billing Service** Customers with small generating capacity - up to 50 kW or to 100 kW, if renewable fuel - can net their generation from their usage.
- Other Available Rates/Riders: Rates 1, 5, 7, 27, 30, 35 and 40.
- Effective 7/1/93

5 Yr. ED **Economic Development Rider** New or Existing Customers that have an option to move into or expand operations in CL&P's service area with an increase of load of 50 kW or more, and that depends on aid and discounts from the State and/or the Company. Maximum duration 5 years.
- Other Available Rates/Riders: Rates 27, 30, 35, 55, 56, 57 and 58.
- Effective 2/5/99

BR **Business Recovery Rider** Provides discounts on a Customer's bill for Customers who are experiencing short-term, reversible financial duress and have a plan for recovery.
- Other Available Rates/Riders: Rates 35, 55, 56, 57 and 58.
- Effective 2/5/99

CPR **Competitive Pricing Rider** Provides discounts on a Customer's bill for Customers who have viable alternatives to full requirements service in CL&P service area.
- Other Available Rates/Riders: Rates 35, 40, 41, 55, 56, 57 and 58.
- Effective 2/5/99

CSR **Construction Standard Rider** Minimum building standards for a house to be allowed the use of electricity as the primary space heating source.
- Other Available Rates/Riders: Rate 5
- Effective 7/1/93

CTAC **Competitive Transition Assessment Cost Adjustment**
- Effective 1/1/00

DRR (closed) **Demand Reduction Rider** Customers who have maximum annual on-peak demands greater than or equal to 350 kW and can interrupt at least 300 kW of load in at least four months of the year within one or four hours of notice. Monthly cre or penalties based on performance.
- Closed to new applicants effective 2/5/99.

CL&P LIST AND APPLICABILITY OF RATES AND RIDERS

- Other Available Rates/Riders: Rates 41, 55, 56, 57 and 58.
- Effective 2/5/99

EAC **Energy Adjustment Clause**
- Effective 1/1/00

GETRR **Gross Earnings Tax Reduction Rider**
- Effective 1/1/00

GS **Generation Services**
- Effective 1/1/00

LTED **Long-Term Economic Development Rider** New or Existing Customers that have an option to move into or expand operations in CL&P's service area with an increase of load of 350 kW or more, and that depends on aid and discounts from the State and/or the Company. Maximum duration 10 years.
- Customers are on or shall be served on Rates 19, 20, 21, 39, 55, 56, 57 or 58.
- Effective 2/5/99

SBCA **Systems Benefits Cost Adjustment**
- Effective 1/1/00

TDR **Transitory Demand Rider** Waives any bill consequences beyond the month of occurrence of a previously approved spike in a Customer's one month's demand above currently prevailing maximum demand.
- All Rates with demand or kW based facilities charges.
- Effective 8/20/91

VCR **Voluntary Curtailment Rate** Customers who have at least 250 kW of interruptible load and can do so at the request of the Company. Provides credit only for actual interruption provided per request.
- Other Available Rates/Riders: Rates 35, 55, 56, 57 or 58.
- Effective 7/1/93

THE CONNECTICUT LIGHT AND POWER COMPANY

BACK-UP AND MAINTENANCE POWER SERVICE

RATE 985

APPLICABILITY: This rate is available to all partial requirements general service customers (the customer) who require back-up and maintenance service. All electricity shall be measured through one meter, except that where the Company deems it impractical to deliver electricity through one service, or where the Company has installed more than one meter, then the measurement of electricity may be by two or more meters. All electricity supplied shall be for the exclusive use of the customer and shall not be resold. Service taken under this rate shall be electrically separated from the customer's generating facilities or provided with sufficient protective devices to prohibit such facilities from causing disturbances on the Company's system. The Company reserves the right to refuse service to facilities where the Company deems the protection provided to be inadequate.

Back-Up Power is intended to provide the customer with a back-up supply of power when the customer's generating facilities are not in operation or are operating at less than full rated capability. To obtain service under this schedule, the customer must specify in writing the maximum demand (Back-Up Contract Demand) which it plans to impose on the Company under this schedule, but not to exceed actual output of the customer's generation.

Demands imposed on the Company by the customer in excess of the customer's Supplemental Contract Demand, under Rate 984, if any, shall be deemed to be Back-Up Power and billed accordingly up to the previously specified Back-Up Contract Demand. When the customer imposed demand exceeds the specified Rate 984 Supplemental Contract Demand plus the Back-Up Contract Demand, the customer imposed demand minus the previously specified Back-Up Contract Demand shall become the customer's new Supplemental Contract Demand.

The customer shall furnish, at the customer's expense, necessary facilities whereby the Company can meter the output of the customer's generating facilities.

MONTHLY RATE: The customer shall be billed for service, in accordance with the applicable general service tariff available to the customer for the size of service taken based on the Back-Up Contract Demand Level except as modified below.

Production/Transmission Demand or Contribution Charge:

Customers shall pay the greater of:

A. D times $(1-(1-K/2080)^6)$ per kW of Production/Transmission in demand,

where D equals the applicable general service rate's Production/Transmission Demand Charge, or, if absent, then the general service rate's total demand charge less $4.05 after January 1, 2000.

Where K equals the sum of the backup/standby loads taken in each on-peak hour of the latest six months of December, January, February, June, July, and August divided by the contracted backup/standby demand, or

B. the Production/Transmission Demand Charge of $1.00 per kW of Back-Up Contract Demand.

BACK-UP AND MAINTENANCE POWER SERVICE
(Continued)

The minimum monthly charge shall be the sum of a) the Customer Service Charge plus b) the product of the Distribution Demand or Facilities Charge and the Back-Up Contract Demand plus c) the Production/Transmission Demand or Contribution Charge determined above.

Where service is taken under this schedule the demand shall be the actual maximum demand less the applicable Supplemental Contract Demand. Billing energy shall be kWh consumed at levels in excess of the Supplemental Contract Demand.

CHARGES INCLUDED IN THE ABOVE RATES, ON AN EQUIVALENT PER-KWH BASIS:

TRANSMISSION	\$0.00120 per kWh
SYSTEMS BENEFITS CHARGE	\$0.00175 per kWh
COMPETITIVE TRANSITION ASSESSMENT	\$0.00987 per kWh
GENERATION SERVICES	\$0.04400 per kWh
CONSERVATION CHARGE	\$0.00300 per kWh

RENEWABLE ENERGY CHARGE PER KWH:

Effective January 1, 2000	\$0.00050 per kWh
Effective July 1, 2002	\$0.00075 per kWh
Effective July 1, 2004	\$0.00100 per kWh

RATE ADJUSTMENTS: This rate will be adjusted as provided in the Company's Energy Adjustment Clause.

COMPETITIVE TRANSITION ASSESSMENT COST ADJUSTMENT:

Competitive Transition Assessment (CTA) charges and terms under this rate includes a CTA Cost Adjustment Charge set in accordance with the Company's CTA Cost Adjustment.

SYSTEMS BENEFITS COST ADJUSTMENT:

Systems Benefits service charges for all customers taking service under this rate shall be set in accordance with the Company's Systems Benefits Cost Adjustment.

TERM OF CONTRACT: The minimum term of service under this, or any superseding rate schedule, is two years.

Supercedes Firm Back-Up and Maintenance
Power Service Rate 985
Effective: July 1, 1993

Effective: January 1, 2000